APPLICATION OF

VIRGINIA ELECTRIC AND POWER COMPANY **CASE NO. PUE980463**

To revise its cogeneration tariff pursuant to PURPA Section 210

REPORT OF DEBORAH V. ELLENBERG, CHIEF HEARING EXAMINER

February 11, 2000

On August 11, 1998, Virginia Electric and Power Company ("Virginia Power" or the "Company") filed with the Commission an application to modify its cogeneration and small power production rates under its Schedule 19. The Commission docketed the proceeding, established a procedural schedule and directed Staff to investigate the reasonableness of the Company's filing.

Notices of protest were filed by Appomatox Cogeneration Limited Partnership ("ACLP"), the Alexandria/Arlington Resource Recovery Corporation, Westvaco Corporation, and St. Laurent Paper Products Corporation.

By motion dated November 9, 1998, the ACLP requested a six-week extension of time for filing protests and testimony. That motion was granted by ruling dated November 10, 1998. A hearing was held as originally scheduled on December 16, 1998, for the sole purpose of receiving statements from public witnesses. None appeared.

On January 14, 1999, Virginia Power filed a Motion for Continuance by which it requested a continuance to allow rebuttal testimony, along with certain studies requested by the Staff, to be filed July 15, 1999, and a hearing set as soon thereafter as possible. Virginia Power asserted in support thereof that such a continuance would allow all parties to consider the impact of the Commission's January 14, 1999, decision in *Application of Virginia Electric and Power Company, For approval of expenditures for new generation facilities*, Case No. PUE980462. Virginia Power also advised that it was willing to perform several of the additional simulation runs requested by Staff on the Company's avoided energy cost forecast to test the sensitivity of energy costs to the avoided block size. The Company, however, disagreed with Staff that there was a need for a one megawatt avoided block analysis. Staff responded and argued that the Company should be directed to perform sensitivity studies including a study with an avoided block size of one megawatt. Staff reasoned that such an analysis was necessary to consider use of market price as an alternative to the differential revenue requirement methodology to compute avoided cost. Staff also advised that if a continuance was granted, the Commission's final determination of the proper energy and capacity payments should be effective as of January 1, 1999.

ACLP also filed a response to the motion. It opposed the motion because the delay would postpone resolution of modeling changes which it proposed in the calculation of avoided cost. It submitted that the Company should be required to file rebuttal testimony on modeling issues now but permitted to file rebuttal testimony addressing the impact of the mid-2000 expansion units on July 15, 1999. By rulings dated January 19 and 21, 1999, I rejected ACLP's recommendation to bifurcate the case. A continuance was granted and Virginia Power was directed to perform sensitivity studies including off-system sales for a 150 MW avoided block, and including and excluding off-system sales for a 100 MW avoided block. Virginia Power was also directed to perform a study to determine the impact on its system resulting from displacing the first 150 MW combustion turbine unit planned for 2000. The Company was not directed to perform a sensitivity study for a 1 MW avoided block, but was directed to fully discuss why such an analysis was unnecessary. It was further directed that the current Schedule 19 payment levels should continue on an interim basis subject to adjustment to reflect the rates approved herein to be effective January 1, 1999. By ruling dated January 26, 1999, the hearing on this application was rescheduled for February 24, 1999.

That hearing was convened as directed. Counsel appearing were: M. Renae Carter, Esquire, and Donald R. Mueller, Esquire, counsel to the Commission; Richard D. Gary, Esquire, and Michael C. Regulinski, Esquire, counsel to Virginia Power; and Mark J. LaFratta, Esquire, counsel to Appomatox Cogeneration Limited Partnership ("ACLP").

Proof of the required notice was marked as Exhibit A and admitted into the record. Copies of the transcripts are filed with this Report.

SUMMARY OF RECORD

In this case Virginia Power proposes to decrease its avoided energy and capacity payments. It proposes to expand the effective period for this schedule through 2001. The Company also proposes to significantly decrease the maximum contract term that can be executed pursuant to Schedule 19. In support of its application, the Company presented the testimony of Mr. Daniel J. Green, W. R. Eckroade, and Mr. J. E. McIntyre, Jr.[1]

The Company utilized PROVIEW, a generation planning computer model, to develop an optimal capacity expansion plan, and PROMOD, a probabilistic computer model used to simulate system operation to derive its proposed payment levels. PROMOD was run assuming no additional qualifying facilities (the "base" case or "without" case), and again, assuming the addition of a block of new capacity with specified operating characteristics at no cost (the "with" case). The difference in the revenue requirement necessary to support each of the two cases was presumed to represent the costs the Company would incur but for the presence of qualifying cogeneration or small power production - the "avoided costs." The difference in the revenue requirements due to capital investments and fixed operating and maintenance expenses are the avoided capacity costs, and the difference in fuel mixes form the basis for avoided energy costs.[2] This differential revenue

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[1]Exhibits DJG-2, WRE-3 and JEM-4.

[2] Exhibit TEL-7, at 3.

requirement ("DRR") methodology has been used to calculate avoided costs for Virginia Power for over ten years.[3]

The Company, however, did make several changes in its calculation in this case. The size of a block of new zero cost capacity from qualifying facilities ("QF") assumed to displace capacity in the base case can affect the resulting avoided costs. In this proceeding the Company proposes to model a 150 MW block of capacity from a QF in the "with" case. In the last case, the Commission approved a block size of 100 MW.[4] In previous cases, a block size of 200 MW has been used.[5] The proposed energy and capacity payments are based on its 1998 resource plan. Mr. Green testified that the plan identified the need for 864 MW of peaking capacity in the year 2000 and additional capacity needs for 2001 and 2002. The Company intends to meet its 2000 need with four 150 MW combustion turbine ("CT") units and unidentified purchases. Mr. Green testified that the block size of the avoided capacity therefore was assumed to equal the size of one of the CT units.[6]

The proposed schedule provides a QF with several operating options with corresponding payments. The QF must meet defined operational criteria for the mode of operation chosen. QFs electing to deliver firm energy and capacity may elect energy payments using a set of annual avoided energy mixes applicable to each year of the contract term.[7] The annual mix may vary from year to year under this option. The Company's proposed 1999 energy payments for each of the options are as follows:[8]

Avoided energy (¢/kWh)	**On-Peak**	**Off-Peak**	**Average**
Non-firm, Non-time Differentiated	1.511	1.511	
Non-firm Time Differentiated	1.628	1.387	
Firm Base Load	1.995	1.444	1.683
Firm Peaking	2.779		

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[3]The DRR methodology was adopted in *Ex Parte: In the matter of adopting appropriate methodology for use in calculating, pursuant to PURPA, the Schedule 19 avoided costs of Virginia Electric and Power Company*, Case No. PUE870081, 1988 S.C.C. Ann. Rep. 301.

[4]*Application of Virginia Electric and Power Company*, Case No. PUE960117, 1998 S.C.C. Ann. Rep. 331.

[5]Id.

[6]Exhibit DJG-1, at 4.

[7]Exhibit JEM-4, at 3.

[8]Exhibit JEM-4, Sch. 1, at 4-6.

For the year 2000 the Company's proposed energy payments for firm sales are estimated to be:[9]

Avoided energy (¢/kW h)	On-Peak	Off-Peak	Average
Firm Base Load	2.312	1.673	1.950
Firm Peaking	2.713		

A QF delivering firm energy and capacity may elect a levelized avoided energy mix applicable for each year of the contract term as an alternative. The fuel costs associated with any of the established fuel mixes are filed each December for the succeeding year.[10]

Only QFs electing to make firm deliveries are eligible to receive capacity payments and then only beginning in 2000. The levelized capacity payments applicable to a firm base load mode of operation are:[11]

Firm Base Load Mode of Operation

Levelized Capacity Purchase Prices (Cents per kWh)

Contract Length (in Years)	Initial Year of Operation 1999	2000	2001
1	0.000	0.387	0.395
2	0.387	0.391	---
3	0.391	---	---

The levelized capacity payments applicable to a firm peaking mode of operation are:[12]

Firm Peaking Mode of Operation

Monthly Levelized Capacity Purchase Prices (Dollars Per kWh)

Contract Length In Years	Initial Year of Operation 1999	2000	2001
1	0.00	1.86	1.94
2	1.86	1.90	---
3	1.90	---	---

The proposed levelized capacity payments are based on Virginia Power's estimated capacity prices for market purchases in 2000-2001.

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[9]Exhibit DJG-2, at 12.

[10]Exhibit JEM-4, Sch. 1, at 4-5.

[11]Id. at 18.

[12]Id. at 19.

Initially the Company also proposed to limit the term of contracts executed under Schedule 19 to three years. It urged the Commission to approve such a limited contract term due to the industry restructuring currently underway. The Company later modified its proposed contract term to up to four years, or through December 31, 2002, asserting such a term would still be consistent with a transition to the competitive market.[13]

Staff filed the testimony of Jarilaos Stavrou, a principal research analyst in the Commission's Division of Economics and Finance and Thomas E. Lamm, an assistant director in the Commission's Division of Energy Regulation.[14] Mr. Stavrou addressed the Company's avoided energy costs and Mr. Lamm addressed the development of the Company's avoided capacity costs, proposed firm capacity payments, and contract term.

Mr. Stavrou testified that although the DRR methodology continues to be acceptable, the Company did not implement the methodology in full compliance with Commission final orders in other Virginia Power cases. Notably, in the last Schedule 19 case the avoided costs were derived using a 100 MW displaced capacity block.[15] In this case the Company used a different block size. Mr. Stavrou observed that the Company changed the avoided block size to 150 MW to match the size of one of the Company's planned CTs, but no CT was avoided in the resulting simulation plans. He testified however that, as addressed further by Staff witness Lamm, one of the proposed CTs could be considered an avoided unit and then a 150 MW block size would be an appropriate change. He concluded that approval of the Company's new CTs[16] could affect the avoided energy mix and associated avoided energy costs in this case.

Mr. Stavrou also testified that the Company did not model off-system energy sales in its forecast of avoided energy costs. The Commission ordered the Company to capture the dispatch effects of off-system energy sales on system operation and performance in the 1997-98 fuel factor.[17] Mr. Stavrou therefore initially contended that off-system sales should be reflected in the calculation of avoided costs.[18]

Mr. Stavrou recommended that the Company perform additional simulation runs to test the sensitivity of energy costs to avoided block size, off-system sales, and the elimination of one of the new CTs from the expansion plan. He provided a matrix in his written testimony to identify the

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[13]Exhibits DJG-2, 5-6 and JLJ-5, 3.

[14]Exhibits JS-6 and TEL-7.

[15]*Application of Virginia Electric and Power Company*, Case No. PUE960117, 1998 S.C.C. Ann. Rep. 331.

[16]*Application of Virginia Electric and Power Company*, Case No. PUE980462, Final Order dated May 14, 1999.

[17]*Application of Virginia Electric and Power Company*, Case No. PUE970904, 1998 S.C.C. Ann. Rep. 386.

[18]Exhibit JS-6, at 11.

combinations of those factors which he recommended be tested for base load and peaking unit scenarios.[19] The Company provided most of those analyses in rebuttal testimony, and after reviewing the simulations run by the Company including off-system sales, Mr. Stavrou further testified that Staff no longer supported including off-system sales in the avoided cost calculations in this case. Staff thus supports the energy payments proposed by the Company.

Mr. Lamm also took issue with the appropriate block size to use in the avoided cost analysis and with the Company's avoided capacity costs. In addition, he addressed the appropriate term limits for Schedule 19 contracts. Mr. Lamm proposed to base avoided capacity costs on the estimated fixed costs of the Company's planned CT units. Mr. Lamm testified that it would be reasonable to use a 150 MW capacity block to derive avoided costs if the Commission decides the avoided capacity costs should be based on the costs of those units. However, if the Commission decides that market purchases should be considered the avoidable capacity, Staff believes that the capacity block should be reduced to 100 MW, at a minimum, consistent with the Commission's determination in the last case.

Addressing the maximum contract term, Staff witness Lamm testified that the length of contract should be a function of the certainty of the need for and the Company's commitment to capacity.[20] Thus, he concludes that if the Commission adopts Staff's recommendation that a CT serve as the basis for the avoided cost calculation, a contract duration of up to 25 years could be justified consistent with the expected life of the unit. He testified that "if the Company is willing to commit to a 25-year construction investment, it should be willing to commit to a 25-year contract investment at comparable cost."[21] He also noted however that the Commission may want to consider the electric industry restructuring and the policy implications of those industry changes. Staff suggests a maximum available contract term of no less than ten years given the Company's imminent and substantial capacity needs, CT additions, and industry restructuring.

In sum, Staff supported the energy payments proposed by the Company for 1999, but recommended that capacity payments scheduled to begin in 2000 should be developed based on the average fixed costs of a CT unit with a maximum contract duration of 10 to 25 years.[22] Staff supports the mismatch between energy and capacity payments because the CT would not be displaced until 2000. Staff reasoned that it might be confusing to base levelized energy payments on one analysis for 1999 and another for 2000 and 2001. However, Staff took the position that it would be acceptable to base avoided energy payments on the displacement of a CT for contracts signed in 2000 or 2001.[23]

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[19]Id. at 10.

[20]Exhibit TEL-7, at 8.

[21]Id. at 9.

[22]Id. at 9, 11.

[23]Tr. 139-140.

St. Laurent Paper Products Corporation, Westvaco Corporation, and ACLP (collectively "Protestants") jointly presented the testimony of Roy J. Shanker.[24] Dr. Shanker recommended that the Commission direct Virginia Power to modify the demand forecast used in Schedule 19 to be consistent with the assumptions for off-system sales used in the Company's most recent fuel factor filing.[25] Dr. Shanker asserts that failing to make such an adjustment would under-compensate QFs. He stated that including such sales would increase forecasted loads, and the forecasted units used to provide energy at the margin would change. Generally, he asserts that such an impact would increase the avoided energy price forecast.[26]

Virginia Power filed the rebuttal testimony of Daniel J. Green and Jeffrey L. Jones.[27] In its rebuttal, the Company presented the results of eleven new sensitivity cases in addition to the three cases originally completed and presented in its direct testimony. The eleven new sensitivity studies were performed at the direction of the Hearing Examiner.[28] Mr. Green argued that off-system sales should not be included in the avoided cost calculation. He also asserted that the Company should not be required to complete a sensitivity case based on a 1 MW block of avoided energy as recommended by Staff witness Stavrou.[29] Mr. Jones opposes Staff's recommendation on maximum contract terms.[30]

DISCUSSION

Schedule 19 establishes the firm and non-firm payments for power purchases from cogenerators or small power producers having a design capacity of 100 kW or less as required by the Public Utility Regulatory Policies Act of 1978 ("PURPA").[31] The Protestants in this case have design capacities much greater than 100 kW and thus are not subject to the terms of Schedule 19 by operation of that schedule. However, pursuant to contracts executed in the early 1980's, the energy payments of the Protestants are tied to the energy payments adopted by the Commission in Schedule 19. Thus their payments are affected by the energy payments approved in this case.[32]

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[24]Exhibit RJS-8.

[25]Id. at 4; *Application of Virginia Electric and Power Company*, Case No. PUE980727, 1998 S.C.C. Ann. Rep. 432.

[26]Exhibit RJS-8, at 6.

[27]Exhibits DJG-2 and JLJ-5.

[28]Ruling dated January 21, 1999.

[29]Exhibit DJG-2, at 18-19.

[30]Exhibit JLJ-5, at 2.

[31]18 C.F.R. § 292.304(c)(1).

[32]Tr. 13.

There were several issues in controversy. Some issues, such as a dispute over maximum contract terms did not affect Protestants, but could significantly affect new small QFs. The issue that generated the majority of attention, however, addressed a modeling assumption. Specifically, the Company, Staff, and Protestants debated factoring off-system sales into the analysis required to derive avoided costs. That issue affects small Schedule 19 QFs and Protestants.

Virginia Power's application proposes revised Schedule 19 payments for a three-year period, 1999-2001. Neither Staff nor Protestants opposed the Company's proposal. The Commission historically has required Virginia Power to file new Schedule 19 rates every other year.[33] That requirement was consistent with federal regulations that direct utilities to file data to support avoided cost calculations biannually.[34] However, I find the Company's proposal is reasonable. Schedule 19 should be approved effective through 2001. The extended effective period will afford the Company, Staff, and independent generators an opportunity to work through restructuring before another case. By 2001, changes that will result from any restructuring should be better defined and will require consideration if avoided costs will still need to be calculated.

Differentiated Revenue Requirement

The Commission has long applied a DRR approach to calculating avoided costs. However, in the last case, the Commission directed the Company and Staff to consider alternative methods to calculate those costs. The Company considered several alternatives, but continues to advocate use of the DRR method. Mr. Green testified that existing contracts with Schedule 19 QFs are tied to rates and energy mixes determined using the DRR method. Contracts with Protestants also are premised on completion of the DRR calculation.[35] If the Company were required to switch methodologies for contracts entered into prospectively, it would still be necessary for avoided costs to be calculated under a DRR approach for previously executed contracts. Further, the Company asserts that abandoning the DRR approach at this time would complicate the transition to competition.[36]

The Staff sought to have the Company perform several additional sensitivity studies in part to better evaluate alternative approaches. Specifically, Staff sought an analysis using only 1 MW of displaced capacity.[37] Staff sought that analysis because it contended that the study would yield the marginal cost relevant to market purchases that could be considered as an alternative for setting avoided costs.

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[33] *Application of Virginia Electric and Power Company*, Case No. PUE890075, 1990 S.C.C. Ann. Rep. 309.

[34] 18 C.F.R. § 292.302(2)(b).

[35] Exhibit DJG-1, at 18.

[36] Id. at 18-19.

[37] Exhibit JS-6, at 10.

The Company opposes Staff's recommendation to run a sensitivity study using a 1 MW block because it asserts that such an analysis is not necessary and runs contrary to Staff positions taken in other cases. Mr. Green testified that the marginal energy cost can be taken directly from PROMOD runs, and therefore, there is no reason to compare a with and without case for a 1 MW block.[38] Moreover, in response to a proposal by Dr. Shanker to reduce the block size to 5 MW in the last case, Staff had testified that a 200 MW block was appropriate, and that a minimum size block of 100 MW should be used if a reduction in block size is required since anything smaller "would be drowned in program noise."[39] Mr. Green reiterated that position and testified that a 1 MW change on the Virginia Power system with 18,000 MW would not be notable.[40]

The Commission adopted Staff's position in the last case and rejected Dr. Shanker's recommendation to calculate avoided costs assuming a 5 MW displacement block.[41]

I find no compelling reason at this time for the Commission to require analyses of a displacement block even smaller than 5 MW. Moreover, at the hearing, Staff advised that it no longer sought the Commission to compel the Company to run a sensitivity study using an avoided block of 1 MW in this case.[42] The Company should not be required to run a sensitivity study on only one avoided megawatt of capacity.

I also find that we should continue to use the DRR calculation in this case. However, Mr. Lamm also cautioned that the Commission should retain flexibility to employ the methodology that fits best given the circumstances of each filing in future cases.[43] I agree. The industry's future is in transition. Flexibility is particularly important during such a time.

Avoided Block Size

The size of the block of capacity considered displaced by QF generation in the DRR analysis continued to be at issue. In the last case, that displacement block was reduced to 100 MW because the first avoided capacity was expected to be undesignated purchases. Although the Commission recognized that purchases can be made in any size, it determined that 100 MW should be used for purposes of calculating rates in that case.[44] In previous cases, the Commission had approved use of

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[38]Exhibit DJG-2, at 19.

[39]*Application of Virginia Electric and Power Company*, Case No. PUE960117, 1998 S.C.C. Ann. Rep. 331, 332.

[40]Tr. 20.

[41]*Supra* 1998 S.C.C. Ann. Rep. 331, 332.

[42]Tr. 154.

[43]Exhibit TEL-7, at 6.

[44]*Supra* 1998 S.C.C. Ann. Rep. 331, 333.

a 200 MW block in the calculation of avoided costs.[45] A 200 MW block was chosen when the DRR methodology was first implemented, because it had a relation to the size of the system and the kind of resources that could be avoided at that time. It was not found to be the proper size for the displacement block for all time.[46]

In this case, the Company used a block size of 150 MW. Staff witness Lamm supports a block size of 150 MW if the Commission finds that the Company should use one of its planned CTs as an avoided unit in its calculations, but he recommends that the block size be no greater than 100 MW if market purchases are considered the displaced capacity. I agree. The block size should be consistent with the available avoidable resource.

Avoidable Capacity

On May 14, 1999, the Commission granted certificates of public convenience and necessity for four new 150 MW gas-fired CT units at a site in Fauquier County.[47] In the context of that certificate case the Company also identified a need to solicit bids for an additional 264 MW to serve its needs by July 1, 2000 and another 850 MW of capacity for delivery in July 2001 and July 2002.[48] The Company thus plans to rely on its own CTs and undesignated purchases to meet its needs in the 2000 to 2002 planning horizon.

The estimated costs of one of those planned CTs can reasonably serve as the basis for avoided costs for this Schedule 19. The estimated costs associated with the CTs were developed to support their approval and as a benchmark for evaluating bids in that recent certificate case.[49] The costs have been well defined. The costs for undesignated purchases, however, are much more uncertain. I find that a 150 MW CT should be assumed to be an avoidable unit for the purpose of calculating avoided costs. I therefore also find that use of a 150 MW block of QF capacity in the calculation is consistent and appropriate.

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[45] Id.

[46] *Application of Virginia Electric and Power Company*, Case No. PUE960117, Hearing Examiner Report at 11 (September 18, 1997).

[47] *Application of Virginia Electric and Power Company*, Case No. PUE980462, Order dated May 14, 1999.

[48] *Application of Virginia Electric and Power Company*, Case No. PUE980462, Order dated January 14, 1999.

[49] Id.

Virginia Power's DRR analysis using a 150 MW block excluding 1 CT, but still excluding off-system sales yielded the following energy payments for 2000:[50]

Avoided energy (¢/kWh)	On-Peak	Off-Peak	Average
Base Load	2.275	1.646	1.919
Peaking	2.422		

Off-System Sales

Also at issue was whether the Company should be required to capture the effects of off-system sales in its calculation of avoided costs. The Company did not model off-system energy sales in its forecast of avoided costs for this case. Staff witness Stavrou initially testified that the Commission had ordered the Company to capture the dispatch effects of off-system sales on system performance in Case No. PUE970904, the Company's 1997-98 fuel factor, since such sales were becoming increasingly important and thus, potentially affected costs. In his prefiled testimony, Mr. Stavrou stated that the Virginia Power system is large and complex, therefore, he could not predict the effects of increased load from off-system sales on costs in a simple way.[51] He testified that the expected effect of additional load would be higher generation costs, but there may be other indirect effects that would counter higher costs. He recommended the Company conduct PROMOD sensitivity analyses[52] to test the effect of including off-system sales. The Company conducted those studies. The analysis revised to include the off-system sales estimates that were included in the Company's 1998 fuel factor proceeding, to eliminate one of the CT units, and to utilize a 150 MW displacement block results in the following 2000 payments:[53]

Avoided energy (¢/kWh)	On-Peak	Off-Peak	Average
Base Load	2.585	1.871	2.181
Peaking	2.586		

After reviewing the results of that analysis, Staff concluded that the study did not appropriately model the sales, and produced anomalous results. With further consideration to the volatility of the wholesale market at this time, Staff testified that off-system sales should not be included in this case. Mr. Stavrou testified that the market should settle out over the next few years and the issue could be revisited.[54]

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[50]Exhibit DJG-2, at 12.

[51]Exhibit JS-6, at 7.

[52]Id.

[53]Exhibit DJG-2, at 13.

[54]Tr. 142.

Dr. Shanker continued to urge the Commission to factor off-system sales into the calculation of avoided costs. He argued that such treatment would be consistent with the treatment of the sales in the fuel factor.[55] In closing argument, counsel for the Protestants argued that the DRR method was designed to compute the effect of capacity modeled at zero cost on total system costs, thus all revenues should be included. [56]

The Company argued that off-system sales should be excluded from the determination of avoided costs because PURPA directs that avoided cost determinations should be based on the costs necessary to meet system native load needs that can be avoided if the utility purchases from a QF rather than obtains the energy from some other source.[57] Mr. Green argues that federal regulations address the utility's obligation under PURPA and provide that the price should only include payment for energy and capacity that the utility can use to serve its native load. In support of that assertion, he refers to the Federal Energy Regulatory Commission ("FERC") order promulgating the regulations. Therein the FERC stated:

> [a] qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load. These rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale.[58]

Virginia Power interprets "total system load" to be synonymous with "native load," and argues that off-system sales are not undertaken for the purpose of meeting native load energy requirements and should not be included. In closing, counsel for Virginia Power argued that limitations in the regulations would be meaningless if all revenue from everything a utility could sell should be considered.[59] Mr. Green asserts that PURPA did not envision or require a utility to market a QF's energy in the wholesale market, which he contends would be the result of including off-system sales in the avoided cost calculation.

The Protestants argue that neither PURPA nor federal regulations limit inclusion of off-system sales.[60] Dr. Shanker argues that system load is not limited to native load as argued by the

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[55]Tr. 92.

[56]Tr. 144.

[57]Exhibit DJG-2, at 3.

[58]F.E.R.C. Regulations Preambles 1977-1981 ¶ 30, 128 at 30, 870 (February 25, 1980).

[59]Tr. 149.

[60]Tr. 93, 147-148.

Company. Protestants contend that if costs are incurred or revenues received within the system, they affect system costs.[61]

The language cited by Virginia Power does not preclude inclusion of off-system sales. Nowhere in PURPA, the applicable federal regulations, or in this Commission's decisions is system load limited to native load. I can find no legal limitation on how this Commission defines "system costs" for purposes of calculating avoided costs.

Both Mr. Green and Dr. Shanker reflected back on their work on the task force that ultimately resulted in use of the DRR approach to calculate avoided costs for Virginia Power. The Task Force Report had the following to say about including off-system sales:[62]

> In situations where the operation of the QF allows the utility to achieve an increased level of off-system sales over the level that could have been undertaken absent the QF operations, the payment to the QF shall be based on the incremental revenues realized from the increased sale of power.

Although Mr. Green testified that in the real world it is impossible to tell if a QF helped achieve an off-system sale in any given hour, the Task Force language clearly envisioned circumstances in which some level of off-system sales could be factored into the analysis.[63]

In past cases, the Company has sought and the Commission has included other non-firm transactions, economy purchases, in the avoided cost calculations.[64] If non-firm expenses are included, revenues should also be included to better reflect total system costs. The Company, however, now contends that all non-firm transactions, including both off-system sales and economy purchases, should be excluded from the calculation of avoided costs. Yet, the goal in calculating avoided costs should be to consider all expenses and revenues that affect system costs and can be estimated with some certainty.

Mr. Green next discussed problems with modeling off-system sales. He testified that he assumed 600 MW hours of sales when he ran the sensitivity study including off-system sales for this case, but he advised that PROMOD did not appropriately model the sales in the hours the Company would most likely make the transactions. In the analysis presented in this case the model spread the off-system sales assumptions across all peak hours which is not realistic, and produced anomalous results. For instance, in the base case including off-system sales, the model results indicated that the Company would have to add 582 MW of firm capacity to make the estimated off-

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[61]Tr. 148.

[62]Green, Tr. 39-40; Shanker, Tr. 94..

[63]Tr. 135-136.

[64]*Supra* 1998 S.C.C. Ann. Rep. 331, 333.

system sales. Mr. Green confirmed that the Company would not build firm capacity to make non-firm sales.[65]

Dr. Shanker agreed that the numbers were wrong. He agreed that the numbers overstated the impact of off-system sales due to the way the modeling was done. He observed that when you input additional load as a flat sale around the clock, you must expect to get anomalous results.[66] He recommended several ways that Virginia Power could have modeled sales to avoid anomalous results. He noted that the Company could modify its load curve based on a historic level of sales. He also testified that an economy purchase module for PROMOD exists that could have been used. Dr. Shanker added he was comfortable that the Company had the necessary forecasts to use the module, although he also acknowledged such forecasts would introduce a new and major analytical element into the calculations.

Mr. Green admitted that the economy purchase module was available but testified that the Company did not have it at the time the calculation for this case was done.[67] He also added that there will be numerous new inputs to evaluate once the module is in use.[68] There is no solution that does not require more analysis.[69]

Protestants however argue that consideration of off-system sales should not be rejected because the Company got anomalous results.[70] Dr. Shanker argued that the Commission can and does reasonably forecast margins and levels of off-system sales in the fuel factor and the time is ripe for consideration in the Schedule 19 case. He contends that excluding consideration of off-system sales results in underpaying the QF.[71] Dr. Shanker testified that Protestants simply seek the best estimate of system load.[72]

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[65]Exhibit DJG-2, at 7.

[66]Tr. 97.

[67]Tr. 117.

[68]Tr. 151.

[69]Tr. 107.

[70]Tr. 97.

[71]Tr. 145.

[72]Tr. 94-95.

The Commission has found that off-system sales have an increasingly significant effect on system operations and should be recognized in the simulation of system performance to derive the fuel factor,[73] although the Commission is currently revisiting consideration in off-system sales in the pending fuel factor proceeding.[74]

This Commission has adopted standards for evaluating the fuel cost projections of electric utilities. Those standards include the following:

> (3) Key input data such as load forecasts, generating unit characteristics, fuel data, and system parameters should be developed in the same relative time frame and reflect consistent assumptions.
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> . . . .
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> (8) Purchase power levels should consider need, system economics, power availability and transmission constraints.
>
> (9) Projections supporting the development of cogeneration rates should include a comparison of key input data and assumptions from the last fuel projection filed with the Commission. Major changes should be adequately explained.[75]

The standards emphasize use of consistent assumptions in the system simulations run to derive avoided costs and the last fuel projections. In adopting those standards, the Commission recognized that fuel cost projections have interrelated applications, and that consistent use is essential to ensure payments to QFs are fair and reasonable. The standards recognize that some variance may be necessary and require explanation of major changes. In my opinion, off-system sales also should be included at some level in the calculation of avoided costs if they are reflected in the fuel factor.

Mr. Green identified and compared historic levels of economy purchases and off-system sales. Historic off-system sales by the Company were 12,963,987 MW hours and 6,736,227 MW hours for 1997 and 1998, respectively.[76] Economy purchases for 1997 and 1998 were 1,072,776 MW hours and 1,457,843 MW hours, respectively. Mr. Green notes that off-system sales are declining and the level of purchases rising because system native load is continuing to grow and the Company has no plans to add generation until the summer of 2000. Thus, the reserve margin

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[73]*Application of Virginia Electric and Power Company*, Case No. PUE970904, 1998 S.C.C. Ann. Rep. 386.

[74]*Application of Virginia Electric and Power Company*, Case No. PUE990717, Order Establishing 2000-2001 Fuel Factor Proceeding dated December 29, 1999.

[75]*Ex Parte, In re: Investigation for Evaluating Fuel Cost Projections of Electric Utilities*, Case No. PUE900004, 1990 S.C.C. Ann. Rep. 319, 320.

[76]Exhibit DJG-2, at 15.

continues to decline and there is less capacity available to make non-firm opportunity sales. As a further indication of declining levels, Mr. Green observed that in January of 1999, the Company made 298,000 MW hours of sales. The January estimate included in the fuel factor was 450,000 MW hours.[77]

Mr. Green recommends that if the Commission orders the Company to include representative non-firm transactions in the avoided cost determination, only conservative estimates of both sales and purchases should be included. He argues that any variances between the fuel factor estimates and actual revenues and costs are corrected with a true-up mechanism. Estimates in avoided cost proceedings cannot be corrected, and therefore, the modeling is more critical. The non-firm economy purchase estimates included in calculating avoided costs were approximately 20% of actual economy transactions. The Company recommends the same approach be applied to off-system sales.[78] Dr. Shanker argues that the levels should be the same as included in the fuel factor.[79]

Mr. Green presented an analysis that included reduced levels of off-system sales. That analysis yields the following 1999 avoided energy rates:

Avoided energy (¢/kWh)	**On-Peak**	**Off-Peak**	**Average**
Base Load	1.962	1.420	1.655
Peaking	2.813		

The results yield avoided cost rates lower than proposed in the Company's application; the Company still recommends approval of the rates filed in its application.[80]

Although I agree that conservative estimates of off-system sales should be factored into the calculation, the fundamental modeling deficiencies in Company's analysis are not corrected by reducing the level of off-system sales in the analysis and no party disputes the anomalous results of the Company's studies including off-system sales. The record contains no credible analyses to derive avoided cost prices that reflect off-system sales. The Company and Protestants also agree that the only way to derive payment levels that factor in off-system sales is to run additional simulations and that would impose additional variables that could be debated.

Based on the record herein, energy payments for any contracts executed in 1999 should receive the energy payments proposed by the Company herein and supported by Staff. Any new contracts in 2000 or 2001 should offer energy payments calculated assuming a 150 MW CT is the

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[77]Tr. 120.

[78]Exhibit DJG-2, at 15.

[79]Tr. 106.

[80]Exhibit DJG-2, at 16.

avoidable unit in the DRR analysis. Although off-system sales are not factored into those analyses, they represent the best available data on this record to support payments.

Consistent with that finding, capacity payments should be based on the Company's estimated costs of one of its 150 MW CTs planned for the summer of 2000.

Contract Term

One final issue must be addressed. In the last case, the Commission limited the maximum contract term available under Schedule 19 to five years.[81] The Company initially proposed to limit the maximum contract term available to Schedule 19 generators to two years in this case. However, the Company later expressed its willingness to modify its proposal and execute contracts under Schedule 19 with terms up to December 31, 2002.[82]

Staff witness Lamm testified that contract length should be a function of need and commitment to capacity. He asserts that if the Commission adopts his recommendation to base avoided costs on one of the Company's proposed CTs, a contract length of 25 years could be justified. On balance, however, after considering the changing electric environment, he recommends a term no less than ten years.[83]

Company witness Jones addressed Staff's recommendation regarding the maximum term of contracts applicable to Schedule 19 rates. He urges the Commission to reject Staff witness Lamm's recommendation for a maximum contract term of 10 to 25 years. Mr. Jones testified that the Company's investment in the new CTs will not be a financial obligation of its customers for 25 years, but rather, once full customer retail choice is implemented, a risk of the Company. He argued that the Commission should not require the execution of contracts that will extend the Company's contractual obligation for capacity beyond that of its obligation to serve all customers.

The Company concludes its argument by noting that the PURPA obligation and a contractual obligation do not have to be the same. If PURPA is still law at the end of the contracts, the Company will still have an obligation to purchase from the QFs and Virginia Power will sign another contract.[84]

Contract term is a subject that has been addressed often. In the last case,[85] the Company and Staff proposed reducing the maximum contract term from 30 years to five years due in large part to

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[81] *Supra* 1998 S.C.C. Ann. Rep. 331.

[82] Exhibit JLJ-5, at 3.

[83] Exhibit TEL-7, at 9, 11.

[84] Tr. 152.

[85] *Supra* 1998 S.C.C. Ann. Rep. 331.

the uncertainties facing the industry as restructuring was being considered, but the Commission clearly stated that its decision was:

> based on the Company's stated intention to acquire capacity in the next few years through purchases under short-term contracts not exceeding five years rather than to build capacity or enter into long-term contracts.[86]

I support Staff's recommendation to now increase the maximum contract term to ten years. As Mr. Lamm observed, the Company is committed to 25-year capacity additions and the costs associated with the CT units. The ten-year term recommended by Staff is significantly lower than the Company's commitment to the CTs. Staff's proposal reasonably balances the uncertainties of a new market and the financial obligations of the contracting parties.

FINDINGS AND RECOMMENDATIONS

Based on the evidence in the record in this proceeding, I find that:

(1) Virginia Power should offer contracts under Schedule 19 for terms up to ten years;

(2) Virginia Power should use a 150 megawatt block of assumed displaced capacity in its DRR calculation;

(3) Avoided energy payments for 1999 as proposed by Virginia Power should be approved;

(4) Avoided energy payments for 2000 and 2001 should be based on avoided energy fuel mixes derived by displacing one of the Fauquier County 150 MW combustion turbines approved for the summer of 2000;

(5) Avoided capacity payments should be based on that same displaced 150 MW CT; and

(6) The payments made under interim rates should be adjusted with revised payments made for power purchased under Schedule 19 since January 1, 1999, as appropriate.

Accordingly, ***I RECOMMEND*** the Commission enter an order:

(1) ***ADOPTING*** the findings set forth above;

(2) ***DIRECTING*** Virginia Power to file a revised Schedule 19 consistent with the findings contained herein within 60 days of a final order in this case; and

(3) ***DISMISSING*** this case from the Commission's docket of active cases.

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[86]Id. at 332.

COMMENTS

The parties are advised that any comments (Section 12.1-31 of the Code of Virginia and Commission Rule 5:16(e)) to this Report must be filed with the Clerk of the Commission in writing, in an original and fifteen (15) copies, within twenty-one (21) days from the date hereof. The mailing address to which any such filing must be sent is Document Control Center, P.O. Box 2118, Richmond, Virginia 23218. Any party filing such comments shall attach a certificate to the foot of such document certifying that copies have been mailed or delivered to all counsel of record and any such party not represented by counsel.

Respectfully submitted,

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Deborah V. Ellenberg
Chief Hearing Examiner